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# Wellbore Models GWELL, GWNACL, and HOLA

## User's Guide

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## NOMENCLATURE

$A$	=	cross-sectional area, $m^2$
$B_R$	=	semi-empirical coefficient for calculating the two-phase multiplier
$B_s$	=	semi-empirical coefficient for calculating the two-phase multiplier
$D$	=	depth of node, m
$C_A$	=	Armand coefficient
$C_{Ah}$	=	Armand coefficient for horizontal pipes
$C_{Av}$	=	Armand coefficient for vertical pipes
$E_t$	=	total energy flux, J/s
$f$	=	friction factor
$F_1$	=	non-linear function 1 in variable $y = (y_1, y_2)$
$F_2$	=	non-linear function 2 in variable $y = (y_1, y_2)$
$G$	=	mass flux, $kg/m^2 \cdot s$
$g$	=	gravity constant, $m/s^2$
$H$	=	enthalpy, kJ/kg
$k$	=	intrinsic permeability, $m^2$
$k_{rl}$	=	liquid relative permeability, $m^2$
$k_{rv}$	=	gas relative permeability, $m^2$
$k$	=	fluid incompressibility, Pa
$K$	=	gas to liquid velocity ratio
$L$	=	depth coordinate, m
$L_B$	=	empirical variable described in Table 4.1
$L_M$	=	empirical variable described in Table 4.1
$L_s$	=	empirical variable described in Table 4.1
$L_w$	=	total length of the well, m
$\dot{m}$	=	mass flow, kg/s

$\vec{m}$	=	mass flow vector, kg/s
$M$	=	Jacobian matrix
$MW$	=	molecular weight
$n$	=	Blasius exponent
$p$	=	vector $(P_1, P_2)$ which makes $F_1(p) = F_2(p) = 0$
$\rho$	=	density, kg/m <sup>3</sup>
$P$	=	pressure, Pa-abs
$P_b$	=	pressure, Bar-abs
$P_r$	=	reservoir pressure, Pa-abs
$P_s(T)$	=	saturation pressure for pure water at a given temperature (Pa)
$P_w$	=	flowing well pressure, Pa-abs
$q$	=	mass flow from Darcy's Law, kg/s
$Q$	=	volumetric flow rate, m <sup>3</sup> /s
$Q_t$	=	ambient heat flux, W/m
$r$	=	radius, m
$r_w$	=	well radius, m
$R$	=	universal gas constant, erg/g-°K
$Re$	=	Reynold's number
$S$	=	gas saturation
$t$	=	time, s
$T$	=	temperature, °C
$T_K$	=	temperature, °K
$\bar{T}_r$	=	mean reservoir temperature, °C
$\bar{T}_w$	=	mean fluid temperature, °C
$u$	=	average velocity, m/s
$u_b$	=	bubble velocity, m/s

$u_{CH}$	=	choked velocity, m/s
$u_H$	=	homogeneous velocity, m/s
$u_T$	=	Taylor bubble (slug) velocity, m/s
$v$	=	specific volume, cm <sup>3</sup> /g
$v_c$	=	specific volume of water at the critical point, cm <sup>3</sup> /g
$\bar{v}_o$	=	specific volume of pure water, cm <sup>3</sup> /g
$v_{gD}$	=	empirical variable described in Table 4.1
$x$	=	mass fraction of gas
$z(P_b, T_K)$	=	CO <sub>2</sub> compressibility factor
$\left[ \frac{dP}{dL} \right]_{acc}$	=	pressure drop component due to acceleration, Pa/m
$\left[ \frac{dP}{dL} \right]_{fri}$	=	pressure drop component due to friction, Pa/m
$\left[ \frac{dP}{dL} \right]_{pot}$	=	pressure drop component due to gravity, Pa/m
$\left[ \frac{dP}{dL} \right]_{GO}$	=	pressure drop component if fluid flows as liquid only, Pa/m
$\left[ \frac{dP}{dL} \right]_{LO}$	=	pressure drop component if fluid flows as gas only, Pa/m
$\alpha$	=	mass fraction of component 2 (i.e. CO <sub>2</sub> , NaCl)
$\mu$	=	dynamic viscosity, kg/m-s
$\phi_{FLO}$	=	two-phase multiplier
$\sigma$	=	surface tension, N/m
$\beta$	=	gas volumetric flow rate ratio
$\epsilon$	=	pipe roughness, m
$\eta$	=	Euler's constant

$\tau$	=	rock thermal conductivity
$\Theta$	=	inclination angle from horizontal, °
$\cap$	=	thermal diffusivity, m <sup>2</sup> /s
$\Omega$	=	thermal conductance, W/m-°C
$\Sigma$	=	productivity index, m <sup>3</sup>
$\Gamma$	=	physical property parameter (see Equation 4.25)
$\Delta$	=	finite difference

### Subscripts

CO <sub>2</sub>	=	Carbon Dioxide (CO <sub>2</sub> )
f	=	feedzone
g	=	gas
H <sub>2</sub> O	=	water
i	=	lower grid node
i-1	=	upper grid node
l	=	liquid
lCO <sub>2</sub>	=	CO <sub>2</sub> in liquid
m	=	mixture
mn <sub>NaCl</sub>	=	molal salt concentration
na <sub>Cl</sub>	=	salt (NaCl)
r	=	reservoir
s	=	steam
soln	=	solution
v	=	vapor
vCO <sub>2</sub>	=	CO <sub>2</sub> in vapor (gas)
w	=	well
y	=	component (total, H <sub>2</sub> O, CO <sub>2</sub> , NaCl)

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## 1.0 INTRODUCTION

This report describes three multi-component, multi-feedzone geothermal wellbore simulators developed. These simulators reproduce the measured flowing temperature and pressure profiles in flowing wells and determine the relative contribution, fluid properties (e.g. enthalpy, temperature) and fluid composition (e.g. CO<sub>2</sub>, NaCl) of each feedzone for a given discharge condition.

The three related wellbore simulators that will be discussed here are HOLA, GWELL and GWNACL. HOLA is a multi-feedzone geothermal wellbore simulator for pure water, modified after the wellbore simulator developed by Bjornsson, 1987 and can now handle deviated wells. The other two simulators GWELL (see also Aunzo, 1990) and GWNACL are modified versions of HOLA that can handle H<sub>2</sub>O-CO<sub>2</sub> and H<sub>2</sub>O-NaCl systems, respectively.

These simulators can handle both single and two-phase flows in vertical and inclined pipes and calculate the flowing temperature and pressure profiles in the well. The simulators solve numerically the differential equations that describe the steady-state energy, mass and momentum flow in a pipe. The codes allow for multiple feedzones, variable grid spacing and well radius. These codes were developed using FORTRAN language on the UNIX system.



## 2.0 GOVERNING EQUATIONS

The flow of fluid in a geothermal well can be represented mathematically by two sets of equations. Between the feedzones, the flow can be represented by one-dimensional steady-state momentum, energy and mass flux balances. When a feedzone is encountered, mass and energy balances between the fluid in the well and the feedzone are performed. The solutions of these equations require fully defined flow conditions at one end of the system (inlet condition), and fully defined boundaries (wellbore geometry, lateral mass and heat flow). The governing equations are then solved in small finite steps along the pipe. Whenever a feedzone is encountered, the mass and energy of inflow (or outflow) are given and mass and energy balances are performed, allowing the calculation to continue farther in the well.

### 2.1 FLOW BETWEEN FEEDZONES

The governing equations describing the flow characteristics of fluid inside a pipe can be described as follows,

#### Mass Balance

$$\frac{d\dot{m}_y}{dL} = 0, \quad y = \text{total, CO}_2, \text{H}_2\text{O, NaCl} \quad (2.1)$$

where,

$\dot{m}$  = mass flow

$L$  = length of pipe

#### Momentum Balance

The total pressure gradient is the sum of the friction gradient, acceleration gradient and potential gradient (head). This can be expressed as,

$$\frac{dP}{dL} - \left[ \frac{dP}{dL} \right]_{fri} - \left[ \frac{dP}{dL} \right]_{acc} - \left[ \frac{dP}{dL} \right]_{pot} = 0 \quad (2.2)$$

where,

$$\left[ \frac{dP}{dL} \right]_{\text{fri}} = \phi_{\text{FLO}}^2 \left[ \frac{dP}{dL} \right]_{\text{LO}}$$

$$\left[ \frac{dP}{dL} \right]_{\text{acc}} = \frac{d(Gu_m)}{dL}$$

$$\left[ \frac{dP}{dL} \right]_{\text{pot}} = \rho g \sin \Theta$$

$\left[ \frac{dP}{dL} \right]_{\text{LO}}$  is the pressure drop for a flowing single-phase liquid and  $\phi_{\text{FLO}}^2$  is the two-phase multiplier, both of which are defined in Chapter 4.  $G$  is the mass velocity,  $u_m$  is the average fluid velocity,  $g$  is the acceleration constant and  $\Theta$  is the well deviation angle from horizontal, and  $\rho$  is the fluid density. The calculations of the individual components of the pressure drop equation are discussed in Chapter 4.

### Energy Balance

$$\frac{dE_t}{dL} \pm Q_t = 0 \quad (2.3)$$

where,

$E_t$  = total energy flux in the well

$Q_t$  = ambient heat loss/gain over a unit distance

The total heat flux gradient,  $\frac{dE_t}{dL}$  is the sum of the discharges in the heat content of the fluid, kinetic and potential energy. This can be expressed as,

$$\frac{dE_t}{dL} = \dot{m} \frac{d}{dL} \left[ h_m + 0.5u_m^2 + g(L_w - D) \right] \quad (2.4)$$

where,

$\dot{m}$  = total mass flow

$h_m$  = enthalpy of the mixture

$u_m$  = average fluid velocity

$g$  = acceleration constant

$L_w$  = total measured length of the well

$D$  = measured depth

The ambient heat flux,  $Q_t$  in Equation (2.3) is calculated from the heat conduction equation, representing heat exchange with the rocks surrounding the well,

$$\frac{1}{r} \frac{\delta}{\delta r} \left[ r \frac{\delta T}{\delta r} \right] = \frac{1}{\alpha} \frac{\delta T}{\delta t} \quad (2.5)$$

where,

- $T$  = temperature
- $r$  = radial distance from the well
- $\alpha$  = rock thermal diffusivity
- $t$  = time

The above equation is evaluated assuming that at the well,  $r_w$ , the temperature is equal to the wellbore fluid temperature,  $T_w$ , and far from the well, the temperature is equal to the reservoir temperature,  $T_\infty$ , such that,

$$\begin{aligned} T(r_w, t) &= T_w \\ T(r, 0) &= T_\infty \\ T(\infty, t) &= T_\infty \end{aligned}$$

An approximate solution can be obtained which is valid when the term  $\alpha t / r_w^2 > 1$  (Carslaw and Jaeger, 1959).

$$Q_t \approx 4\tau\pi(T_w - T_r) \left[ \ln \left[ \frac{4\alpha t}{r_w^2} - 2\eta \right] \right]^{-1} \quad (2.6)$$

where,

- $\eta$  = 0.577216... (Euler's constant)
- $\tau$  = rock thermal conductivity
- $\alpha$  = rock thermal diffusivity

Equation (2.6) is only an approximate solution and does not take into account transient changes in temperature when the well is discharging. Additional heat losses due to convection in the vicinity of the wellbore are also neglected. However, the term  $\frac{dE}{dL}$  in Equation (2.4) is usually much larger than  $Q_t$ , and therefore the approximate solution is reasonable.

## 2.2 MASS AND ENERGY BALANCES AT THE FEEDZONES

Assuming that instantaneous mixing occurs between the fluid inside the wellbore and the feedzone fluid, and that mixing occurs at the wellbore pressure, then the mass and energy balances can be expressed as,

### Mass Balance

(a) Total Mass

$$\dot{m}_m = \dot{m}_w - \dot{m}_f \quad (2.7)$$

(b) Component 1 (H<sub>2</sub>O)

$$\dot{m}_m(1-\alpha_m) = \dot{m}_w(1-\alpha_w) - \dot{m}_f(1-\alpha_f) \quad (2.8)$$

(c) Component 2 (CO<sub>2</sub> or NaCl)

$$\dot{m}_m\alpha_m = \dot{m}_w\alpha_w - \dot{m}_f\alpha_f \quad (2.9)$$

where,

$\dot{m}$  = massflow (vectors are used since flow can assume two directions)

$\alpha$  = total mass fraction of component 2

subscripts m, w and f stand for mixture, well and feedzone, respectively.

The flow from the feedzone can be specified by the user either as input parameter or the code can compute the flowrate using productivity indices for each feedzone. In the latter case, the feedzone flowrate can be calculated using Darcy's Law,

$$q = kA \left[ \frac{k_{r1} P_1}{\mu_1} + \frac{k_{rv} P_v}{\mu_v} \right] \left[ \frac{dP}{dr} \right] \quad (2.10)$$

where,

$q$  = mass flow

$A$  = area for flow

$k$  = intrinsic permeability

$k_{r1}$  = relative permeability to liquid

$$\begin{aligned}
k_{rv} &= \text{relative permeability to vapor} \\
\mu_l &= \text{viscosity of liquid} \\
\mu_v &= \text{viscosity of vapor} \\
\rho_l &= \text{density of liquid} \\
\rho_v &= \text{density of vapor} \\
\frac{dP}{dr} &= \text{pressure gradient}
\end{aligned}$$

and,

$$k_{rv} = S \quad (2.11)$$

$$k_{rl} = 1 - S \quad (2.12)$$

where,

$$S = \text{saturation}$$

### Energy Balance

$$\dot{m}_m H_m = \dot{m}_w H_w - \dot{m}_f H_f \quad (2.13)$$

where,  $H$  = fluid enthalpy as described in Chapter 4

The mass flow in the well can have two possible directions: upward (when the well is producing) and downward (when the well is under injection). Similarly, the flow from the feedzone has two possible directions: towards the well (producing) and towards the reservoir (injecting). Thus, there are six possible flow configurations that can occur in the well. These six possible configurations are shown schematically in Figure 2.1.

### 3.0 NUMERICAL REPRESENTATIONS

The governing differential equations shown in Chapter 2.0 can be solved numerically by discretizing the well into finite size grid blocks. The numerical representations of these equations are given below.

#### 3.1 BETWEEN FEEDZONES

The total pressure drop can be expressed as:

$$\frac{P_i - P_{i-1}}{\Delta L} - \left[ \frac{\Delta P}{\Delta L} \right]_{fri} - \left[ \frac{\Delta P}{\Delta L} \right]_{acc} - \left[ \frac{\Delta P}{\Delta L} \right]_{pot} = 0 \quad (3.1)$$

and

$$\frac{E_{ti} - E_{ti-1}}{\Delta L} \pm Q_t = 0 \quad (3.2)$$

The subscripts  $i$  and  $i-1$  refer to the lower and upper grid nodes, respectively, at a distance  $L$  apart. The components of the total pressure drop can be expressed as,

$$\left[ \frac{\Delta P}{\Delta L} \right]_{acc} = \frac{(Gu_m)_{i-1} - (Gu_m)_i}{\Delta L} \quad (3.3)$$

$$\left[ \frac{\Delta P}{\Delta L} \right]_{pot} = \frac{(P_{mi-1} \sin \theta_{i-1} + P_{mi} \sin \theta_i) g}{2} \quad (3.4)$$

$$\left[ \frac{\Delta P}{\Delta L} \right]_{fri} = \frac{\left[ \frac{\Delta P}{\Delta L} \right]_{i-1} + \left[ \frac{\Delta P}{\Delta L} \right]_i}{2} \quad (3.5)$$

The total energy flux at any cross-section in the well is the sum of the heat content of the fluid, the kinetic energy and potential energy.

$$E_{ti} = \dot{m}_i [H_m + 0.5 (xu_v^2 + (1-x)u_l^2 + g(L_w - D))]_i \quad (3.6)$$

Equations (3.1) and (3.2) give two non-linear equations in terms of two independent variables. In the single-phase region, for all the three simulators, the primary variables chosen are temperature and pressure. However, in the two-phase region, pressure and mass fraction of vapor (gas),  $x$ , are chosen as the primary variables for the simulators HOLA and GWNACL. However, unlike for pure water

where the two-phase region falls on a single saturation curve, the two-phase region in the  $H_2O-CO_2$  system is bounded by a  $P_{max}$  and  $P_{min}$  (see Figure 5.2). In this case, using temperature and pressure instead of pressure and mass fraction of vapor (gas),  $x$ , is computationally more efficient for the simulator GWELL.

Consider Equations (3.1) and (3.2) as twice differentiable and continuous functions  $F_1(y)$  and  $F_2(y)$  for two variables  $P_1$  and  $P_2$ . A solution  $P=(P_1, P_2)$  which makes  $F_1(P)=F_2(P)=0$  can be obtained by first guessing  $y = y^* = y(y_1^*, y_2^*)$ . A new iterative value of  $y$  is given by,

$$\begin{bmatrix} y_1 \\ y_2 \end{bmatrix} = \begin{bmatrix} y_1^* \\ y_2^* \end{bmatrix} - M^{-1} \begin{bmatrix} F_1(y^*) \\ F_2(y^*) \end{bmatrix} \quad (3.7)$$

where  $M$  is the Jacobian matrix:

$$M = \begin{bmatrix} \frac{\delta F_1(y^*)}{\delta y_1} & \frac{\delta F_1(y^*)}{\delta y_2} \\ \frac{\delta F_2(y^*)}{\delta y_1} & \frac{\delta F_2(y^*)}{\delta y_2} \end{bmatrix} \quad (3.8)$$

If a solution  $P$  exists and all the first and second derivatives of  $F_1$  and  $F_2$  are bounded, then  $y$  will converge quadratically to  $P$ .

The derivatives inside the Jacobian matrix are discretized as follows,

$$\frac{\delta F_1(y_1^*, y_2^*)}{\delta y_1} = \frac{F_1(y_1^* + y_1, y_2^*) - F_1(y_1^*, y_2^*)}{y_1} \quad (3.9)$$

where,

$$y_1 = \text{a small fraction of } y_1^*$$

Also, the thermal conductance for each node is calculated as,

$$\Omega = 4\tau\pi \left[ \ln \left[ \frac{4\eta t}{r_w^2} - 2\eta \right] \right]^{-1} \quad (3.10)$$

The heat loss,  $Q$ , can then be computed as,

$$Q = \Omega ( \bar{T}_w - \bar{T}_r ) \quad (3.11)$$

where,

$\bar{T}_w$  = mean fluid temperature between two adjacent nodes

$\bar{T}_r$  = mean reservoir temperature between two adjacent nodes

### 3.2 AT FEEDZONES

If a feedzone exists at, say node i, the thermodynamic properties of the mixture are calculated assuming an imaginary node, m, where mixing occurs simultaneously at a pressure equal to the pressure of node i. The mass flow, enthalpy and composition of the mixture are then evaluated using Equations (2.7), (2.8) and (2.9) (see Chapter 2.0).

Flow from or into the feedzone can be evaluated by expressing Equation (2.10) as follows,

$$\dot{m}_f = \frac{kA}{r} \left[ \frac{k_{r1} P_1}{\mu_1} + \frac{k_{rv} P_v}{\mu_v} \right] (P_r - P_w) \quad (3.12)$$

$P_r$  and  $P_w$  are the pressures in the reservoir and well, respectively, and  $r$  is the distance to the reservoir at  $P_r$ . The parameter  $kA/r$  can be lumped together to form a group called the *Productivity Index*,  $\Sigma$ . The Equation (2.23) can be expressed as,

$$\dot{m}_f = \Sigma \left[ \frac{k_{r1} P_1}{\mu_1} + \frac{k_{rv} P_v}{\mu_v} \right] (P_r - P_w) \quad (3.13)$$

It should be noted that the above definition of the Productivity Index,  $\Sigma$ , is not the same as that used in the petroleum industry.



## 4.0 THEORY OF TWO-PHASE FLOW IN VERTICAL AND INCLINED PIPES

### 4.1 INTRODUCTION

The problem of accurately predicting pressure drop in two-phase flow is difficult since, two-phase flows are complex and difficult to analyze even for limited conditions studied. Under some conditions, the gas moves at a much higher velocity than the liquid. Also, the liquid velocity along the pipe wall can vary appreciably over a short distance and result in a variable friction loss. Under other conditions, the liquid is almost completely entrained in the gas and has very little effect on the wall friction loss. The difference in velocity and the geometry of the two phases strongly influence pressure drop. These factors provide the basis for categorizing two-phase flows (Orkiszewski, 1967).

In two-phase flows, it is customary to treat the flow of liquid and gas separately using the well established theory of single-phase flow. These equations are then extended for two-phase flows using empirical correlations. Here, these empirical equations are taken from Chisholm (1983). The notations used and the presentation of the equations are patterned after Bjornsson (1987).

### 4.2 SINGLE PHASE FLOW

The flow of single-phase fluid in pipes is treated extensively in fluid mechanics literature. The flow calculations are carried out using linear equations assuming that the fluid properties remain relatively constant. The components of the total pressure drop (pressure drop due to friction, potential and acceleration) can be expressed as,

$$\left[ \frac{dP}{dL} \right]_{\text{fri}} = \frac{fG^2}{4r_w P} \quad (4.1)$$

$$\left[ \frac{dP}{dL} \right]_{\text{pot}} = \rho g \sin \theta \quad (4.2)$$

$$\left[ \frac{dP}{dL} \right]_{\text{acc}} = \frac{d(Gu)}{dL} \quad (4.3)$$

where,

$f$  = friction factor

$G$  = mass velocity

- $r_w$  = well radius
- $\rho$  = density of fluid
- $g$  = gravity constant
- $\theta$  = deviation angle from horizontal
- $u$  = average fluid velocity

Note that all parameters (symbols) and their units are given in the Nomenclature.

The friction factor  $f$ , is given by White (1979),

If  $Re < 2400$ :

$$f = \frac{64}{Re} \quad (4.4)$$

If  $Re > 2400$ :

$$\frac{1}{f} = -2.0 \log_{10} \left[ \frac{\frac{\epsilon}{2r_w}}{3.7} + \frac{2.51}{Re f^{0.5}} \right] \quad (4.5)$$

where,

- $Re$  = Reynolds number
- $\epsilon$  = pipe roughness

## 4.3 TWO-PHASE FLOW

### 4.3.1 Basic Definitions

This section introduces the important expressions and ratios used for two-phase flow. These formula are taken after Chisholm (1983) and presented in the same form as that expressed by Bjornsson (1987).

#### Mass Fraction

$$x = \frac{\dot{m}_v}{\dot{m}} = \frac{\dot{m}_v}{\dot{m}_v + \dot{m}_l} \quad (4.6)$$

where,

$\dot{m}$  = mass flow rate  
subscripts v and l stand for gas and liquid, respectively.

### Mass Velocity

$$G = \frac{\dot{m}_v + \dot{m}_l}{A_v + A_l} \quad (4.7)$$

where,

A = cross-sectional area  
 $A_v$  = cross-sectional area occupied by the gas  
 $A_l$  = cross-sectional area occupied by the liquid

### Velocity Ratio

$$K = \frac{u_v}{u_l} \quad (4.8)$$

where,

u = velocity

### Continuity Equation

$$\dot{m}_v = u_v \rho_v A_v = u_v \rho_v S A \quad (4.9)$$

$$\dot{m}_l = u_l \rho_l A_l = u_l \rho_l S A \quad (4.10)$$

### Gas Saturation

$$S = \frac{A_v}{A} = \frac{A_v}{A_v + A_l} \quad (4.11)$$

From Equations (4.6) to (4.11), S can also be expressed in terms of K and x.

$$S = \left[ 1 + K \frac{(1-x) \rho_v}{x \rho_l} \right]^{-1} \quad (4.12)$$

### Gas, Liquid and Homogeneous Velocities

Combining Equations (4.6) to (4.11), the following relations can be derived,

$$u_v = G \left[ \frac{x}{P_v} + \frac{K(1-x)}{P_1} \right] \quad (4.13)$$

$$u_1 = \frac{G}{K} \left[ \frac{x}{P_v} + \frac{K(1-x)}{P_1} \right] \quad (4.14)$$

When the velocity ratio,  $K$ , is unity, the phase velocities are the same. This velocity is known as the homogeneous velocity,  $u_H$ .

$$u_H = G \left[ \frac{x}{P_v} + \frac{(1-x)}{P_1} \right] \quad (4.15)$$

### Volumetric Flow Rates

$$Q_v = A_v u_v = \frac{x G A}{P_v} \quad (4.16)$$

$$Q_1 = A_1 u_1 = \frac{x G A}{P_1} \quad (4.17)$$

### Gas Volumetric Flowrate Ratio

$$\beta = \frac{Q_v}{Q_v + Q_1} = \left[ 1 + \frac{1-x}{x} \frac{P_v}{P_1} \right] \quad (4.18)$$

### Density of Mixture

$$P_m = S P_v + (1-S) P_1 \quad (4.19)$$

An alternative expression for the mixture density can be obtained as a function of the mass fraction,  $x$ , and velocity ratio,  $K$ . By combining Equations (4.12) and (4.19),  $P_m$  can be expressed as,

$$P_m = \frac{x + K(1-x)}{\left[ \frac{x}{P_v} + \frac{K(1-x)}{P_1} \right]} \quad (4.20)$$

## **Choked Flow**

Choked flow occurs when the maximum possible flowrate through a pipe is achieved. This occurs when the total pressure gradient is required to overcome the changes in momentum flux. The choke velocity in two-phase flow is estimated to be (Kjaraan and Eliasson, 1983),

$$u_{CH} = \left[ \frac{k_m}{P_m} \right] \quad (4.21)$$

and,

$$\frac{1}{k_m} = \frac{S}{k_v} + \frac{(1-S)}{k_l} \quad (4.22)$$

where,

$$k = \text{fluid incompressibility} = \frac{p}{\rho} \frac{d\rho}{dp}$$

subscripts m, v, and l stand for mean, gas and liquid respectively.

The flow is assumed choked when  $u_{CH} > u_H$ , the homogeneous fluid velocity.

### **4.3.2 Description and Determination of Flow Regimes**

Generally for a flowing geothermal well, one encounters different flow regimes along its entire length. Any correlation developed specifically for any one of these conditions would be inadequate to describe the flow behavior in the entire well. Thus, an accurate description of the flow behavior in a pipe entails identifying the different flow regimes. In this work, the definitions used by Orkiszewski (1967) are used to describe the different two-phase flow regimes. These are: bubble, slug, transition (slug-annular) and annular-mist (see Figure 4.1).

Orkiszewski (1967) developed a correlation used to identify the different flow regimes. He based his correlations by analysing pressure data from 148 oil wells. The criteria are tabulated in Table 4.1.

**TABLE 4.1**  
**FLOW REGIMES AND CRITERIA (after Bjornsson, 1987)**

FLOW REGIME	CRITERIA
Bubble	$\beta < L_B$
Slug	$\beta > L_B$ and $v_{gD} < L_s$
Transition	$L_s < v_{gD} < L_M$
Mist	$L_M < v_{gD}$

where,

$$v_{gD} = \frac{xG}{p_v} \left[ \frac{p_1}{g\sigma} \right]^{0.25} \quad (\sigma = \text{surface tension})$$

$$v_t = G \left[ \frac{x}{p_v} + \frac{(1-x)}{p_1} \right]$$

$$L_B = 1.071 - 0.676 \frac{v_t^2}{2r_w} \quad \text{and } L_B > 0.13$$

$$L_s = 50 + 36 v_{gD} \frac{Q_1}{Q_v}$$

$$L_M = 50 + 36 \left[ v_{gD} \frac{Q_1}{Q_v} \right]^{0.75}$$

$$\beta = \frac{Q_v}{Q_v + Q_1}$$

### 4.3.3 Pressure Drop due to Friction

#### 4.3.3.1 Vertical Pipes

The pressure drop for two-phase flow can be evaluated using the concept of "two-phase multiplier" (Martinelli and Nelson, 1948).

$$\left[ \frac{dP}{dL} \right]_{2p} = \phi_{FLO}^2 \left[ \frac{dP}{dL} \right]_{LO} \quad (4.23)$$

where,

$$\begin{aligned} \phi_{FLO}^2 &= \text{two-phase multiplier} \\ \left[ \frac{dP}{dL} \right]_{2p} &= \text{two-phase frictional pressure drop} \\ \left[ \frac{dP}{dL} \right]_{LO} &= \text{single-phase liquid frictional pressure drop (Equation 4.1)} \end{aligned}$$

A generalized correlation of the two-phase multiplier has been presented by Chisholm (1983), independent of flow regime. It has the following form,

$$\phi_{FLO}^2 = 1 + (\Gamma^2 - 1) [B_g x^{(2-n)/n} (1-x)^{(2-n)/n} + x^{(2-n)}] \quad (4.24)$$

where,

$$\begin{aligned} \Gamma^2 &= \text{physical property parameter} \\ B_g &= \text{semi-empirical coefficient} \\ n &= \text{Blasius exponent; 0.25 for smooth pipes; 0 for fully rough flow} \\ &\quad (\text{geothermal wells}) \end{aligned}$$

$\Gamma^2$  is defined as the ratio of the pressure drop if the fluid is single-phase gas to the pressure drop if the fluid is single-phase liquid. This can be expressed as,

$$\Gamma^2 = \frac{\left[ \frac{dP}{dL} \right]_{GO}}{\left[ \frac{dP}{dL} \right]_{LO}} = \left[ \frac{\mu_v}{\mu_l} \right]^n \left[ \frac{P_l}{P_v} \right] \quad (4.25)$$

where,

$$\begin{aligned} \mu &= \text{viscosity} \\ \rho &= \text{density} \\ n &= \text{Blasius exponent} \end{aligned}$$

subscripts LO, GO, v and l stand for liquid only, gas only, gas and liquid respectively.

The coefficient  $B_g$  is evaluated using Table 4.2. To correct for the surface roughness of the pipe, Chisholm suggested the relationship,

$$\frac{B_r}{B_s} = \left[ 0.5 \left[ 1 + \left[ \frac{\mu_v}{\mu_l} \right]^2 + 10^{(-300\epsilon/r_w)} \right] \right]^{(0.25-n)/n} \quad (4.26)$$

where,

$\epsilon$  = pipe roughness

$r_w$  = pipe radius

Then for geothermal wells ( $n=0$ ), Equation (4.24) above can be simplified to,

$$\phi_{FLO}^2 = 1 + (\Gamma^2 - 1) [B_R x(1 - x) + x^2] \quad (4.27)$$

**TABLE 4.2**

VALUES OF  $B_S$  FOR SMOOTH PIPES (from Chisholm, 1983)

$\Gamma$	$G$ (kg/m <sup>2</sup> s)	$B_s$
$\leq 9.5$	$\leq 500$	4.8
	$500 \leq G \leq 1900$	$2400/G$
	$\geq 1900$	$55/G^{1/2}$
$9.5 < \Gamma < 28$	$\leq 600$	$520/(\Gamma G^{1/2})$
	$> 600$	$21/\Gamma$
$\geq 28$		$15000/(\Gamma^2 G^{1/2})$

#### 4.3.3.2 Inclined Pipes

For steam-water mixtures Haywood et. al. (1961) obtained a large amount of data for both horizontal and vertical pipes and found that no significant influence of pipe inclination was observed.

At present time, no available methods have been found to predict the effect of inclination angle in frictional pressure drop (Chisholm, 1983). Therefore, in this study, the correlation for vertical pipes was used for inclined pipes.

#### 4.3.4 Velocities of Individual Phases

Two methods are presented here to evaluate the velocities of gas and liquid phases used in the evaluation of the momentum flux and energy equations. These methods are based on empirical correlations.



#### 4.3.4.1 Armand Correlation

Armand (1946) correlated data for the saturation,  $S$ , during air/water flow in pipes. He proposed the relationship,

$$S = C_A \beta \quad (4.28)$$

where,

$\beta$  = gas volumetric flowrate ratio, evaluated using Equation (4.18)

$C_A$  = Armand Coefficient

Chisholm (1983) reviewed Armand's approach and correlated it with the results from the work done by Beggs (1972) to include effects of pipe inclination. He recommended several equations for calculating  $C_A$  for horizontal, vertical and inclined pipes. These equations are tabulated in Table 4.3.

#### 4.3.4.2 Orkiszewski Correlation

The phase velocities can also be calculated using the correlations developed based on the flow regimes as defined by Orkiszewski (1967). The general equation for the calculation of gas phase velocity is,

$$u_v = u_H + \begin{cases} u_b \\ \text{or} \\ u_T \end{cases} \quad (4.29)$$

##### Bubble Flow

For this regime, the bubble velocity is evaluated from the correlation given by Govier and Aziz (1972).

$$u_b = 1.53 \left[ \frac{g \sigma (P_v - P_1)}{P_1^2} \right]^{\frac{1}{4}} \quad (4.30)$$

##### Slug Flow

$$u_T = 0.35 \left[ 2r_w g \left[ 1 - \frac{P_v}{P_1} \right] \right]^{\frac{1}{2}} \quad (4.31)$$

TABLE 4.3

EQUATIONS FOR THE ARMAND COEFFICIENT (after Chisholm, 1983)

$\beta$	$\theta$	EQUATIONS
<0.9	Horizontal (0°)	$\frac{1}{C_{Ah}} = 0.7 + \frac{0.3}{[1 - 0.7(1 - v_l/v_v)]^{1/2}}$
	Vertical (90°)	<p><b>For:</b>  <math>u_H &lt; \frac{u_{WD}}{(1/C_{Ah}) - 1} ; C_{Av} = C_{Ah}</math></p> <hr/> <p><b>For:</b>  <math>u_H &gt; \frac{u_{WD}}{(1/C_{Ah}) - 1} ; w = 14 \left[ \frac{v_v}{v_l} \right]^{0.2} \left[ 1 - \frac{v}{v_v} \right]^5</math></p> <p><b>If,</b>  <math>D &gt; 19 \left[ \frac{\sigma v_l}{g(1 - v_l/v_v)} \right]^{1/2} ,</math>  <math>\frac{1}{C_{Av}} = 1 \pm \frac{1.53w}{u_H} \left[ \frac{g(v_v - v_l)v_v \sigma}{v_v} \right]^{1/2}</math></p> <p><b>If,</b>  <math>D &lt; 19 \left[ \frac{\sigma v_l}{g(1 - v_l/v_v)} \right]^{1/2} ,</math>  <math>\frac{1}{C_{Av}} = 1 \pm \frac{0.35w}{u_H} \left[ \frac{g(v_v - v_l)v_v \sigma}{v_v} \right]^{1/2}</math></p> <p><b>Negative sign for downflow</b></p>
		$C_A = C_{Ah} - (C_{Av} - C_{Ah}) \left[ \frac{\sin 1.8\theta - (1/3)\sin^3 1.8}{0.3} \right]$
>0.9	All	$\frac{1}{C_A} = 1 + \frac{23}{u_H} \left[ \frac{\mu_l \mu_v v_v}{D} \right]^{1/2} \left[ 1 - \frac{v_l}{v_v} \right]$

**Mist Flow**

In the mist flow, velocities of both phases are assumed to be equal (homogeneous) and thus,

$$u_v = u_l = u_H \quad (4.32)$$

### Transition Flow

In the transition regime, a linear interpolation between bubble velocity in slug and mist flow regimes is used. This is expressed as follows,

$$u_b = \left[ \frac{L_M - v_{gD}}{L_M - L_s} \right] u_T \quad (4.33)$$

where,

$u_H$  = homogeneous velocity as defined by Equation (4.15)

$u_b$  = bubble velocity

$u_T$  = slug velocity

$L_M$ ,  $v_{gD}$  and  $L_s$  are empirical variables defined in Table 4.1.

Also by combining Equations (4.6), (4.7), (4.9) and (4.0), the expression for the liquid phase velocity can be derived. The value of  $u_l$  can be evaluated by solving simultaneously Equations (4.34) and (4.35) to yield:

$$u_l = \frac{G - u_v P_v S}{P_l (1-S)} \quad (4.34)$$

$$S = \frac{G x}{u_v P_v} \quad (4.35)$$

## 5.0 EQUATIONS OF STATE

### 5.1 WATER-CARBON DIOXIDE SYSTEM ( $\text{CO}_2\text{-H}_2\text{O}$ )

The mixture  $\text{CO}_2\text{-H}_2\text{O}$  is of great interest in the analysis of geothermal systems, since geothermal water often contains a significant amount of  $\text{CO}_2$ . Several workers have looked into the effects of  $\text{CO}_2$  on the thermodynamics of geothermal fluids. Sutton (1976) and Sutton and McNabb (1977) have conducted studies on the effect of  $\text{CO}_2$  on the boiling curves at Broadlands geothermal field New Zealand. Pritchett et al. (1981) also looked into the effects of  $\text{CO}_2$  on the Baca Geothermal Reservoir, New Mexico. Gaulke (1986) demonstrated the use of  $\text{CO}_2$  in the evaluation of geothermal reservoirs.

For pure water, the two-phase region is defined by the loci of points known as the saturation curve. This is shown in Figure 5.1. If the actual fluid pressure is below the saturated pressure for a given temperature, then the fluid exists as a single phase steam. If the fluid pressure is above the saturated pressure at the given temperature, then the fluid can only exist as liquid water. All two-phase conditions are confined to lie on the saturation curve.

When  $\text{CO}_2$  is present, two effects have been found to occur on the region of the saturation curve (Pritchett et al., 1981). First, the boiling point pressure (pressure at which two-phase starts to form) for a fixed temperature increases. This means that if a system consisting of pure water in the compressed-liquid state undergoes pressure decrease, the fluid will turn two-phase as the saturation pressure is reached. If a certain amount of  $\text{CO}_2$  is present, the pressure at which two-phase starts to form ( $P_{\min}$ ) will be greater than the saturation pressure for pure water. As more  $\text{CO}_2$  is added, the pressure difference becomes higher. On the other hand, if a fluid consisting of water and  $\text{CO}_2$  initially at the gaseous state is compressed, liquid water will start to form at a particular pressure ( $P_{\max}$ ) in the absence of  $\text{CO}_2$ , this will occur at the saturation pressure. In the presence of  $\text{CO}_2$ , the pressure at which liquid starts to form was found to be only slightly greater than for pure water. Consequently, with the presence of  $\text{CO}_2$ , the boiling pressure will exceed the condensation pressure (the pressure at which a gaseous mixture condenses). Both pressures will exceed the saturation pressure for pure water shown as dashed line in Figure 5.2. Figure 5.2 shows a pressure vs. temperature plot for system containing 1% total mass fraction  $\text{CO}_2$ . The width of the two-phase region, shown as a shaded area in Figure 5.2 will increase with increasing  $\text{CO}_2$ .

### **5.1.1 CRITERIA FOR DETERMINING THE STATE OF THE FLUID**

Depending upon the value of total pressure, temperature and the total mass fraction of  $\text{CO}_2$ , the fluid can exist as: (1) an all-liquid solution of  $\text{CO}_2$  in water, (2) a mixture of liquid solution and gas, or (3) an all-gas solution of  $\text{CO}_2$  in steam.

#### **5.1.1.1 All-Liquid Solution of $\text{CO}_2$ and $\text{H}_2\text{O}$**

If the total pressure is greater than the saturation pressure of pure water at the given temperature and the solubility of  $\text{CO}_2$  in water is greater than the given total mass fraction of  $\text{CO}_2$ , then the fluid is in the liquid state.

#### **5.1.1.2 Two-Phase**

If the total pressure is greater than the saturation pressure of pure water at the given temperature but the solubility of  $\text{CO}_2$  in water is less than the given mass fraction of  $\text{CO}_2$ , then a corresponding gas phase will exist. The fluid then exists in a two-phase condition.

#### **5.1.1.3 All-Gas**

If the total pressure is less than or equal to the saturation pressure of pure water at the given temperature and mass fraction of  $\text{CO}_2$ , then the fluid can only exist as an all-gas state.

### **5.1.2 PARTITIONING OF $\text{CO}_2$ BETWEEN LIQUID AND GAS PHASE**

Extensive experimental work on the solubility of  $\text{CO}_2$  in water has been done by Takenouchi and Kennedy (1964). Ellis and Golding (1963) also investigated the solubility of  $\text{CO}_2$  in water and in NaCl solutions of up to 2 molal.

#### **5.1.2.1 Solubility of $\text{CO}_2$ in Water**

A fit on the data by Takenouchi and Kennedy (1964) was shown by Pritchett et al. (1981) to obey the following relationship,

$$\alpha_{1\text{CO}_2} = \frac{P_{\text{CO}_2}}{A + BP_{\text{CO}_2}} \quad (5.1)$$

where,

$\alpha_{1\text{CO}_2}$  = mass fraction of  $\text{CO}_2$  in liquid

$P_{\text{CO}_2}$  = the partial pressure of  $\text{CO}_2$  in the coexisting gas phase

A and B are constants evaluated as functions of temperature.

The partial pressure of  $\text{CO}_2$  is evaluated as follows,

$$P_{\text{CO}_2} = P - P_s(T) \quad (5.2)$$

where,

$P_s(T)$  = saturation pressure for  $\text{H}_2\text{O}$  at a given temperature.

The functions A and B are calculated by polynomials of the form

$$A_0 + A_1T + A_2T^2 \quad (5.3)$$

where,

T = temperature in  $^{\circ}\text{C}$

The values of the coefficients are tabulated in Table 5.1.

**TABLE 5.1**

**VALUES OF COEFFICIENTS FOR CALCULATION OF  $\text{CO}_2$  SOLUBILITY**

SUBSCRIPT	A	B
0	1.03549E+03	2.04465E+01
1	1.60369E+01	-1.07449E-01
2	-4.83594E-02	1.44701E-04

### 5.1.2.2 Mass Fraction $\text{CO}_2$ in Gas

For states of geothermal interest, the mass fraction of  $\text{CO}_2$  in gas which is in equilibrium with the liquid fits the experimental data of Takenouchi and Kennedy (1964) according to the relation,

$$\alpha_{\text{vCO}_2} = \frac{P_{\text{CO}_2}}{P} \quad (5.5)$$

where,

- $\alpha_{\text{vCO}_2}$  = mass fraction  $\text{CO}_2$  in gas phase
- $P_{\text{CO}_2}$  = partial pressure of  $\text{CO}_2$  as expressed by Equation (5.2)
- $P$  = the total pressure

For cases of dry gas (all gas state), the above relation becomes,

$$\alpha_{\text{CO}_2} = \frac{P_{\text{CO}_2}}{P} \quad (5.6)$$

where,

- $\alpha_{\text{CO}_2}$  = total mass fraction of  $\text{CO}_2$

Equations 5.5 and 5.6 above fit the experimental data better than Dalton's Law, which states that the mole fraction of the component gas is proportional to its partial pressure.

### 5.1.3 DENSITY

#### 5.1.3.1 Carbon Dioxide ( $\text{CO}_2$ )

The density of  $\text{CO}_2$  is calculated from the expression obtained from Pritchett et al. (1981).

$$P_{\text{CO}_2} = \frac{P_b}{z(P_b, T_K) R T_K} \times 10^9 \quad (5.7)$$

where,

- $P_{\text{CO}_2}$  = density of  $\text{CO}_2$  in  $\text{kg/m}^3$
- $R$  = the gas constant,  $1.88919\text{E}6 \text{ erg/g-}^\circ\text{K}$
- $T_K$  = temperature in  $^\circ\text{K}$
- $P_b$  = pressure in bars
- $z(P_b, T_K)$  = gas compressibility factor evaluated using an analytical fit of the data by Vargaftik (1975).

For pressures less than 300 bars,

$$z(P_b, T_K) = A + B(P_b - 300) + C(P_b - 300)^2 + D(P_b - 300)^3 + E(P_b - 300)^4 \quad (5.8)$$

For pressures greater than 300 bars,

$$z(P_b, T_K) = A + B(P_b - 300) + F(P_b - 300)^2 \quad (5.9)$$

where,

$P_b$  = the pressure in bars

$T_K$  = the temperature in °K

The temperature dependent coefficients are evaluated from,

$$A = A_0 + A_1 T_K + A_2 T_K^2 + A_3 T_K^3 + A_4 T_K^4 \quad (5.10)$$

$$B = B_0 + B_1 T_K + B_2 T_K^2 + B_3 T_K^3 + B_4 T_K^4 \quad (5.11)$$

$$C = C_0 + C_1 T_K + C_2 T_K^2 + C_3 T_K^3 + C_4 T_K^4 \quad (5.12)$$

$$D = D_0 + D_1 T_K + D_2 T_K^2 + D_3 T_K^3 + D_4 T_K^4 \quad (5.13)$$

$$E = \frac{1 - A + 300B - 300^2 C + 300^3 D}{300^4} \quad (5.14)$$

$$F = F_0 + F_1 T_K + F_2 T_K^2 + F_3 T_K^3 + F_4 T_K^4 \quad (5.15)$$

The values of the coefficients given in Table 5.2 give a satisfactory fit to the experimental data between 77 to 350°C.

TABLE 5.2

VALUES OF COEFFICIENTS FOR CALCULATION OF CO<sub>2</sub> DENSITY

	A	B	C	D	F
0	8.09759	-3.62183E-02	-3.43992E-03	-2.10949E-05	6.82528E-05
1	-7.10670E-02	3.73836E-04	2.77555E-05	1.66021E-07	-6.70714E-07
2	2.38501E-04	-1.32285E-06	-8.30370E-08	-4.86891E-10	2.37181E-09
3	-3.36774E-07	1.97631E-09	1.09429E-10	6.31079E-13	-3.57746E-12
4	1.72976E-10	-1.06781E-12	-5.36712E-14	-3.05175E-16	1.95665E-15

### 5.1.3.2 Mixtures

#### 5.1.3.2.1 Liquid

Since the amount of CO<sub>2</sub> dissolved in the liquid phase is small (low solubility of CO<sub>2</sub> in water), it is assumed that the density of the liquid is equal to the density of pure water at the same temperature. So,



$$p_1 \approx p_{H_2O} \quad (5.16)$$

where,

$$\begin{aligned} p_1 &= \text{the density of mixture} \\ p_{H_2O} &= \text{the density of pure water} \end{aligned}$$

#### 5.1.3.2.2 Gas

For the gas mixture, the same expression used by Sutton (1976) and Pritchett et al. (1981) is used.

$$p_g = p_s + p_{CO_2} \quad (5.17)$$

where,

$$\begin{aligned} p_s &= \text{the density of steam} \\ p_{CO_2} &= \text{the density of } CO_2 \end{aligned}$$

Both values of density are evaluated at the given temperature and corresponding partial pressures.

### 5.1.4 ENTHALPY

#### 5.1.4.1 Carbon Dioxide ( $CO_2$ )

The enthalpy of  $CO_2$  is evaluated using the formula given by Sweigert et al. (1946).

$$\begin{aligned} H_{CO_2} = & 1688 + 1.542T_K - 794.8 \log_{10}(T_K) - \frac{4.135E+04}{T_K} \\ & - \frac{3.571E-04 P_{CO_2}}{(T_K/100)^{10/3}} (1 + 7.576E-08 P_{CO_2}) \end{aligned} \quad (5.18)$$

where,

$$\begin{aligned} H_{CO_2} &= \text{the enthalpy of } CO_2 \text{ in kJ/kg} \\ P_{CO_2} &= \text{the partial pressure of } CO_2 \text{ in Pa} \\ T_K &= \text{the temperature in } ^\circ K \end{aligned}$$

### 5.1.4.2 Heat of Solution

The heat of solution of a gas is the change in enthalpy brought about by the dissolution of the gas in water. The equation of the heat of solution is calculated using a polynomial fit to the experimental data obtained by Ellis and Golding (1963) and is valid for temperatures in the range 100-300°C.

$$H_{\text{soln}} = -71.33 - 6.0198T + 0.07438T^2 - 2.9244E-04T^3 + 4.4522E-07T^4 \quad (5.19)$$

where,

$$\begin{aligned} H_{\text{soln}} &= \text{the heat of solution in kJ/kg} \\ T &= \text{temperature in } ^\circ\text{C} \end{aligned}$$

### 5.1.4.3 Enthalpy of the Mixture

The enthalpy of the mixture is evaluated using,

$$H_m = xH_v + (1 - x)H_l \quad (5.20)$$

where,

$$\begin{aligned} x &= \text{mass fraction of gas phase} \\ H_v &= \text{enthalpy of the gas phase in kJ/kg} \\ H_l &= \text{enthalpy of the liquid phase in kJ/kg} \end{aligned}$$

The liquid and gas phase enthalpies are evaluated as average enthalpies of the different components weighted by their individual mass fractions.

$$H_l = (1 - \alpha_{\text{lCO}_2})H_w + \alpha_{\text{vCO}_2}(H_{\text{CO}_2} + H_{\text{soln}}) \quad (5.21)$$

and,

$$H_v = (1 - \alpha_{\text{vCO}_2})H_s + \alpha_{\text{vCO}_2} H_{\text{CO}_2} \quad (5.22)$$

where,

$$\begin{aligned} \alpha &= \text{mass fraction CO}_2 \\ H &= \text{enthalpy, kJ/kg} \end{aligned}$$

The subscripts l, v, w, s, lCO<sub>2</sub>, vCO<sub>2</sub> and soln stand for liquid phase, gas phase, water, steam, CO<sub>2</sub> in liquid phase, CO<sub>2</sub> in gas phase and solution respectively.

The total mass fraction of the gas phase,  $x$ , is calculated using a mass balance on  $\text{CO}_2$ .

$$x = \frac{\alpha_{\text{CO}_2} - \alpha_{1\text{CO}_2}}{\alpha_{\text{vCO}_2} - \alpha_{1\text{CO}_2}} \quad (5.23)$$

## 5.1.5 VISCOSITY

### 5.1.5.1 Carbon Dioxide ( $\text{CO}_2$ )

Fits to the viscosity of  $\text{CO}_2$  as a function of pressure and temperature are based on the data tabulated by Vargaftik (1975). For the viscosity,  $\mu_{\text{CO}_2}$ , in poise,

$$\mu_{\text{CO}_2} = (A + BT + CT^2 + DT^3 + ET^4) \times 10^{-8} \quad (5.24)$$

where,

$$T = \text{temperature in } ^\circ\text{C}$$

The pressure dependent coefficients are found from the linear interpolation between the tabulated values in Table 5.3.

### 5.1.5.2 Mixture

The viscosity of the liquid phase is assumed to be approximately equal to the viscosity of pure water since the amount of dissolved  $\text{CO}_2$  is small. For the gas phase, a weighted average is used.

$$\mu_1 \approx \mu_{\text{H}_2\text{O}} \quad (5.25)$$

$$\mu_v = \alpha_{\text{vCO}_2} \mu_{\text{CO}_2} + (1 - \alpha_{\text{vCO}_2}) \mu_g \quad (5.26)$$

## 5.1.6 SURFACE TENSION

The effect of  $\text{CO}_2$  on the surface tension of water has been studied by Heuer (1957) as part of his Ph.D. dissertation. He measured the interfacial tension of  $\text{H}_2\text{O}-\text{CO}_2$  at different temperatures and partial pressures of  $\text{CO}_2$  ( $P_{\text{CO}_2}$ ). The results are shown in Figure 5.3.

**TABLE 5.3**

**VALUES OF COEFFICIENTS FOR CALCULATION OF CO<sub>2</sub> VISCOSITY**

P (bars)	A	B	C	D	E
0	1357.8	4.9227	-2.96610E-03	2.85290E-06	-2.18290E-09
100	3918.9	-35.984	2.58250E-01	-7.11780E-04	6.95780E-07
150	9660.7	-135.479	9.00870E-01	-2.47270E-03	2.41560E-06
200	13156.6	-179.352	1.12474	-2.98864E-03	2.85911E-06
300	14796.8	-160.731	8.50257E-01	-1.99076E-03	1.73423E-06
400	15758.3	-144.887	6.73731E-01	-1.41990E-03	1.13548E-06
500	16171.6	-125.341	5.00750E-01	-9.04721E-04	6.19087E-07
600	16839.4	-115.700	4.08927E-01	-6.35032E-04	3.53981E-07

Although the results showed that interfacial tension decreases with increasing P<sub>CO2</sub>, partial pressures greater than 10 bars at the wellhead rarely occur in geothermal well discharge fluids. At P<sub>CO2</sub> lower than 10 bars, the decrease in surface tension is less than 15%. Therefore in this study, the interfacial tension of H<sub>2</sub>O-CO<sub>2</sub> is assumed to be approximately the same as that for pure water.

$$\sigma_m \approx \sigma_{H_2O} \quad (5.27)$$

where,

$$\begin{aligned} \sigma_m &= \text{surface tension of mixture} \\ \sigma_{H_2O} &= \text{surface tension of water} \end{aligned}$$

## 5.2 WATER-SODIUM CHLORIDE SYSTEM (H<sub>2</sub>O-NACL)

The total dissolved solids in geothermal brines varies from that of ordinary well water up to concentrated solutions as high as 40% by weight. Sodium chloride (NaCl) is typically 70 to 80% of the total dissolved solids. The other most abundant components are potassium chloride (KCl), calcium chloride (CaCl<sub>2</sub>) and silica (SiO<sub>2</sub>). The silica concentration in geothermal brines is usually between 200 and 600 ppm (Wahl, 1977). Since NaCl is the major component of the total dissolved solids, the geothermal brine can be treated as a solution of NaCl in water to evaluate its fluid properties. The principal effects of dissolved solids are boiling point elevation, increased viscosity, increased density, increased surface tension and decreased specific heat.

## 5.2.1 CRITERIA FOR DETERMINING THE STATE OF THE FLUID

At a constant pressure, the boiling point temperature of the solution increases as the salt concentration increases. This is shown in Figure 5.4. Depending upon these saturation curves, the fluid can exist as single-phase liquid, single-phase gas or two-phase fluid.

### 5.2.1.1 Single-Phase Liquid

If the total pressure is greater than the saturation pressure at a given temperature and salt concentration in brine, the fluid is in the liquid state.

### 5.2.1.2 Two-Phase

If the total pressure is equal to the saturation pressure at a given temperature and salt concentration in brine, then the fluid is in two-phase condition.

### 5.2.1.3 Single-Phase Gas

The other remaining case is for single-phase steam. This occurs if the total pressure is less than the saturation pressure at the given temperature and salt concentration.

## 5.2.2 SOLUBILITY OF NaCl IN WATER

The solubility of NaCl in water as a function of temperature is obtained from a polynomial fit of the data presented by Haas, 1976. The equation is valid for temperature between 80 to 325°C.

$$S = 26.218166 + 7.199079E-03 T + 1.060020E-04 T^2 \quad (5.28)$$

where,

S            = solubility in wt%  
T            = temperature in °C.

### 5.2.3 SATURATION TEMPERATURE

The boiling point of brine at a given pressure and salt concentration can be evaluated from the expression given by Haas, 1976. This expression is a fit of the experimental data between -11 to 300 °C.

$$\ln T_o = \frac{\ln T_{sat}}{a + bT_{sat}} \quad (5.29)$$

where,

$T_o$  = saturation temperature of pure water pressure, °K.

$T_{sat}$  = saturation temperature of brine solution, °K.

a,b are the coefficients from the polynomial fit.

The coefficients, a and b, are functions of the salt concentration and can be evaluated using the expression below:

$$a = 1 + a1(\alpha_{mnac1}) + a2(\alpha_{mnac1})^2 + a3(\alpha_{mnac1})^3 \quad (5.30)$$

$$b = b1(\alpha_{mnac1}) + b2(\alpha_{mnac1})^2 + b3(\alpha_{mnac1})^3 + b4(\alpha_{mnac1})^4 + b5(\alpha_{mnac1})^5 \quad (5.31)$$

where,

$\alpha_{mnac1}$  = salt concentration

a1 = 5.93582E-06

a2 = -5.19386E-05

a3 = 1.23156E-05

b1 = 1.15420E-06

b2 = 1.41254E-07

b3 = -1.92476E-08

b4 = -1.70717E-09

b5 = 1.05390E-10

### 5.2.4 SATURATION PRESSURE

The vapor pressure of the brine  $P_{sat}$  at a given brine temperature T can be calculated from (Haas, 1976)

$$\ln P_{\text{sat}} = e_0 + \frac{e_1}{z} + \frac{e_2}{z} (10^{e_3 w^2} - 1.0) + e_4 10^{(e_5 y^{1.25})} \quad (5.32)$$

where,

$$\begin{aligned} P_{\text{sat}} &= \text{saturation pressure, bars} \\ e_0 &= 12.50849 \\ e_1 &= -4.616913\text{E}+03 \\ e_2 &= 3.193455\text{E}-04 \\ e_3 &= 1.1965\text{E}-11 \\ e_4 &= -1.013137\text{E}-02 \\ e_5 &= -5.7148\text{E}-03 \\ e_6 &= 2.9370\text{E}+05 \\ y &= 647.27 - T_o \\ z &= T_o + 0.01 \\ w &= z^2 - e_6 \end{aligned}$$

$T_o$  is the equivalent temperature of pure water and can be evaluated from Equation 5.29 by setting  $T_{\text{sat}}$  equal to the brine temperature,  $T$ .

### 5.2.5 DENSITY

The density of vapor-saturated brine solution is evaluated using the formula given by Haas, 1976. For compressed liquid, the expression presented by Phillips et al., 1981 is used. For single phase vapor condition, the density is calculated equal to the density of pure steam at the given temperature and pressure.

#### Liquid Brine

##### (a) Vapor-Saturated

$$P_1 = \frac{1000 + \alpha_{\text{mnacl}} MW_{\text{nacl}}}{1000 \bar{v}_{P_o} + \alpha_{\text{mnacl}} v_{\text{nacl}}} \quad (5.33)$$

where,

$$\begin{aligned} MW_{\text{nacl}} &= \text{molecular weight of NaCl} \\ \alpha_{\text{mnacl}} &= \text{NaCl concentration, molal} \\ \bar{v}_o &= \text{specific volume of pure water, cm}^3/\text{g} \\ v_{\text{nacl}} &= \text{apparent molal volume of NaCl in water, cm}^3/\text{mol} \end{aligned}$$

The apparent molal volume,  $v_{\text{nacl}}$ , can be calculated using the expression:

$$v_{\text{nacl}} = v_{\text{nacl}}^* + k_k (\alpha_{\text{nacl}})^{1/2} \quad (5.34)$$

where,

$$v_{\text{nacl}}^* = c_0 + c_1 \bar{v}_o + c_2 \bar{v}_o^2 \quad (5.35)$$

$$k_k = (c_3 + c_4 \bar{v}_o) \left[ \frac{\bar{v}_o}{v_c - \bar{v}_o} \right] \quad (5.36)$$

and,

$$\bar{v}_o = \frac{v_c + c_5 T_d^{1/3} + c_6 T_d + c_7 T_d^4}{1 + c_8 T_d^{1/3} + c_9 T_d} \quad (5.37)$$

where,

$v_c$  = specific volume of water at critical point (3.1975 cm<sup>3</sup>/g)

$c_0$  = -167.219

$c_1$  = 448.55

$c_2$  = -261.07

$c_3$  = -13.644

$c_4$  = 13.97

$c_5$  = -0.315154

$c_6$  = -1.203374E-03

$c_7$  = 7.48908E-13

$c_8$  = 0.1342489

$c_9$  = -3.946263E-03

$T_d$  = temperature difference between water at critical point and brine temperature both expressed in °K  
= (647.27 - T)

(b) Compressed Liquid

$$P_1 = -3.033405 + 10.128163 XX - 8.750567 XX^2 + 2.663107 XX^3 \quad (5.38)$$

and,

$$XX = -9.9559e^{(-4.539E-03\alpha_{\text{mnacI}})} + 7.0845e^{(-1.638E-04T)} + 3.9093 e^{(2.551E-05P_b)} \quad (5.39)$$



where,

$$\begin{aligned} P_1 &= \text{brine density, g/cm}^3 \\ T &= \text{brine temperature, } ^\circ\text{C} \\ P_b &= \text{pressure, bars} \end{aligned}$$

### Vapor

The density of the vapor is calculated equal to the density of pure steam at the given temperature and pressure.

### 5.2.6 ENTHALPY

The liquid and vapor enthalpies are evaluated using the polynomial fit of the data tabulated by Haas, 1976. The equations given below with the enthalpy expressed in kJ/kg are valid in the range 80-325 °C up to a salt concentration of 30%. at higher salt concentrations, the equations are valid between 170-325 °C.

$$H_1 = AA_0 + AA_1T + AA_2T^2 + AA_3T^3 + AA_4T^4 + AA_5T^5 \quad (5.40)$$

$$H_v = BB_0 + BB_1T + BB_2T^2 + BB_3T^3 + BB_4T^4 + BB_5T^5 \quad (5.41)$$

where,

$$\begin{aligned} H_1 &= \text{brine enthalpy, kJ/kg} \\ H_v &= \text{vapor enthalpy, kJ/kg} \\ T &= \text{temperature, } ^\circ\text{C} \end{aligned}$$

The values of the coefficients at different salt concentrations (in mass fractions) are tabulated in Tables 5.4 and 5.5.

### 5.2.7 VISCOSITY

#### Brine Solution

The viscosity of the brine solution decreases with increasing temperature and increases with increased salt concentration. The viscosity of the brine solution is expressed by Phillips et al., 1981 as function relative to the viscosity of pure water. The equation, given below, is valid for temperatures between 10-350°C, pressures between 0.1-50 MPa and salt concentrations of 0-5 molal.

$$\frac{\mu_1}{\mu_{H_2O}} = 1 + 0.0816\alpha_{mnac1} + 0.0122\alpha_{mnac1}^2 + 1.28E-04\alpha_{mnac1}^3 + 6.29E-04T[1 - e^{(-0.7\alpha_{mnac1})}] \quad (5.42)$$

where,

$$\begin{aligned} \mu_1 &= \text{viscosity of brine, kg/m-s} \\ \mu_{H_2O} &= \text{viscosity of pure water, kg/m-s} \\ T &= \text{temperature, } ^\circ\text{C} \\ \alpha_{mnac1} &= \text{salt concentration, molal} \end{aligned}$$

### Vapor

Viscosity of the vapor is taken to be equal to the viscosity of pure steam at the given temperature and pressure.

### 5.2.8 SURFACE TENSION

In an ionic solution, the increased electrostatic forces resulting from the ions will increase the forces of attraction on the surface layers of water molecules, thus increasing the surface tension of an ionic salt solution. The surface tension of the brine solution can be calculated using the formula presented below (Wahl, 1977):

$$\sigma = 0.00757(374.15 - T)^{0.776}(1 + 0.0039w_t + 4.35E-05w_t^2) \quad (5.43)$$

where,

$$\begin{aligned} \sigma &= \text{surface tension, dyne/cm} \\ T &= \text{temperature, } ^\circ\text{C} \\ w_t &= \text{salt concentration, wt\%} \end{aligned}$$

TABLE 5.4

VALUES OF AA COEFFICIENTS FOR CALCULATION OF BRINE ENTHALPY

NaCl (wt%)	AA <sub>0</sub>	AA <sub>1</sub>	AA <sub>2</sub>	AA <sub>3</sub>	AA <sub>4</sub>	AA <sub>5</sub>
0	24.3283	3.4590	7.7423E-3	-3.8710E-5	9.8560E-8	-6.6832E-11
2.84	3.8978	3.9660	1.5473E-3	-1.0486E-5	4.1365E-8	-4.0272E-11
5.00	-8.6554	4.2491	-1.8147E-3	3.6084E-6	1.6307E-8	-3.5661E-11
5.52	-2.9781	4.0648	1.3506E-4	-7.0009E-6	4.3088E-8	-6.2676E-11
8.06	6.4063	3.7396	2.8065E-3	-2.1195E-5	8.1121E-8	-1.1220E-10
10.00	-7.7332	4.0169	3.4854E-4	-1.5552E-5	8.5077E-8	-1.3786E-10
10.47	-7.0980	3.9819	7.2529E-4	-1.8598E-5	9.6257E-8	-1.5404E-10
12.75	-25.1930	4.4954	-6.0681E-3	1.8814E-5	-1.4513E-9	-6.1698E-11
14.92	-21.7218	4.3128	-4.5295E-3	9.7266E-6	2.4261E-8	-9.3763E-11
15.00	-24.3103	4.4095	-5.9033E-3	1.8744E-5	-3.5968E-9	-6.1554E-11
16.98	-13.3055	4.0101	-1.9609E-3	-2.7629E-6	5.2988E-8	-1.2188E-10
18.95	-20.1016	4.1503	-4.4275E-3	1.2487E-5	8.3083E-9	-7.4095E-11
20.00	-17.9762	3.9897	-2.3208E-3	-2.1036E-6	5.4212E-8	-1.2821E-10
20.82	-26.3103	4.2246	-5.4460E-3	1.6101E-5	4.1867E-9	-7.6350E-11
22.61	-17.0245	3.8503	-2.2900E-3	2.6043E-6	2.9538E-8	-9.2192E-11
24.32	-15.2398	3.6756	-9.8531E-4	-2.5180E-6	3.7287E-8	-9.3442E-11
25.00	-17.7890	3.6737	-9.6132E-4	-3.5030E-6	4.1930E-8	-9.9377E-11
25.96	-23.8474	3.7443	-1.9361E-3	1.8178E-6	2.7380E-8	-8.2566E-11
27.53	-13.0809	3.3248	1.2043E-3	-8.0111E-6	3.5269E-8	-7.2261E-11
29.03	68.5197	1.5947	1.3268E-2	-4.5410E-5	7.9375E-8	-7.3478E-11
30.00	201.1564	0.0333	1.3960E-2	4.9802E-6	-1.3669E-7	1.9756E-10
30.47	168.2466	0.2923	1.4842E-2	-1.0985E-5	-8.0984E-8	1.3746E-10
31.86	-649.4048	9.8268	-1.2149E-2	-8.1793E-5	3.7204E-7	-4.2856E-10
33.19	-1076.2268	13.5234	-2.5886E-2	-2.2676E-5	1.4012E-7	-8.6452E-11
34.47	-2232.6724	20.3039	-2.2856E-2	-6.2959E-5	8.0256E-9	3.2632E-10
35.00	397.1754	2.2554	-1.9632E-2	1.0808E-4	-1.9957E-7	1.4452E-10
35.70	1970.7611	-10.1111	1.5597E-2	1.1827E-6	1.8907E-7	-3.8994E-10
36.89	-313.7351	7.9131	-8.4302E-3	-6.8802E-5	1.8988E-7	-1.2079E-11

TABLE 5.5

VALUES OF BB COEFFICIENTS FOR CALCULATION OF VAPOR ENTHALPY

NaCl (wt%)	BB <sub>0</sub>	BB <sub>1</sub>	BB <sub>2</sub>	BB <sub>3</sub>	BB <sub>4</sub>	BB <sub>5</sub>
0	2446.2217	3.4338	-1.7216E-2	7.6865E-5	-1.9086E-7	1.2083E-10
2.84	2480.0190	2.3510	-4.2241E-3	4.0796E-6	1.6907E-9	-6.9543E-11
5.00	2434.6228	3.6958	-1.9244E-2	8.3982E-5	-2.0143E-7	1.3176E-10
5.52	2454.7854	3.1093	-1.2826E-2	5.0779E-5	-1.1951E-7	5.4818E-11
8.06	2484.1694	2.2481	-3.3417E-3	1.8000E-6	7.740E-10	-5.4977E-11
10.00	2431.6914	3.8447	-2.1670E-2	1.0180E-4	-2.5914E-7	2.0658E-10
10.47	2415.4656	4.3380	-2.7300E-2	1.3222E-4	-3.3733E-7	2.8420E-10
12.75	2461.3501	2.9921	-1.2452E-2	5.5057E-5	-1.4612E-7	1.0537E-10
14.92	2447.1401	3.4389	-1.7747E-2	8.5107E-5	-2.2691E-7	1.9117E-10
15.00	2458.7734	3.0840	-1.3672E-2	6.3005E-5	-1.6990E-7	1.3500E-10
16.98	2492.6707	1.9952	-5.5975E-4	-1.0853E-5	2.7151E-8	-6.2805E-11
18.95	2492.5652	2.0271	-1.2558E-3	-4.9829E-6	7.1859E-9	-3.6303E-11
20.00	2472.6506	2.6476	-8.5314E-3	3.5514E-5	-9.9648E-8	7.2592E-11
20.82	2505.2444	1.6385	3.2375E-3	-2.9188E-5	6.9588E-8	-9.5816E-11

TABLE 5.5 (cont.)

VALUES OF BB COEFFICIENTS FOR CALCULATION OF VAPOR ENTHALPY

NaCl (wt%)	BB <sub>0</sub>	BB <sub>1</sub>	BB <sub>2</sub>	BB <sub>3</sub>	BB <sub>4</sub>	BB <sub>5</sub>
22.61	2438.7627	3.6664	-2.0065E-2	9.7918E-5	-2.6003E-7	2.3340E-10
24.32	2428.1958	3.9949	-2.3862E-2	1.1884E-4	-3.1406E-7	2.8816E-10
25.00	2492.0708	2.0675	-1.9891E-3	1.6513E-6	-1.5052E-8	-3.6188E-12
25.96	2451.8728	3.2611	-1.5332E-2	7.2512E-5	-1.9423E-7	1.7102E-10
27.53	2453.2974	3.2404	-1.5424E-2	7.5312E-5	-2.0672E-7	1.8930E-10
29.03	2471.5308	1.6846	9.5170E-3	-8.4284E-5	2.4727E-7	-2.8731E-10
30.00	1797.5771	11.4452	-3.2958E-2	-7.3318E-5	5.6141E-7	-8.0888E-10
30.47	2962.7830	-4.1519	1.9015E-2	4.1715E-5	-3.4740E-7	4.6296E-10
31.86	5955.7783	-39.2518	1.1080E-1	3.7794E-4	-2.2914E-6	2.9113E-9
33.19	1683.0183	10.9433	-2.8603E-2	-1.8258E-5	1.9546E-7	-2.4958E-10
34.47	4599.6313	-16.6867	4.7566E-2	-4.3308E-5	1.1615E-7	-3.1449E-10
35.00	2567.8904	0.8219	5.1158E-3	-1.2072E-5	-1.3523E-8	1.7705E-11
35.70	6230.8574	-24.1874	3.7339E-2	-3.8967E-5	5.2955E-7	-1.1057E-9
36.89	-2193.3730	35.7752	-1.8214E-2	-3.6811E-4	9.0074E-7	-5.6251E-10

## 6.0 DESCRIPTION OF THE SIMULATOR

### 6.1 OVERVIEW OF PROGRAM STRUCTURE AND EXECUTION

When program execution commences, the first menu prompts for the variable MODE. There are eight options available in this menu. After selecting the option in the first menu, the program goes to the second menu and prompts for a value of the variable ANS. In the second menu, the user chooses one of the two input options. These two input options will be described in detail below. After choosing the input option, the program then goes back into the first menu. The input data can either be read from a file or the user can directly input it from the terminal. A simplified flowchart is shown in Figure 6.1. Tabulated in Table 6.1 are a short description of the subroutines.

**TABLE 6.1**  
**DESCRIPTION OF THE SUBROUTINES**

FUNCTION	SUBROUTINES		
	HOLA	GWELL	GWNACL
main program	HOLA	GWELL	GWNACL
menu	VALM1, VALM2	VALM1, VALM2	VALM1, VALM2
data input	CHANGE, INFILE, INKEY, OUTFILE	CHANGE, INFILE, INKEY, OUTFILE	CHANGE, INFILE, INKEY, OUTFILE
output	OUTPUT1, OUTPUT2	OUTPUT1, OUTPUT2	OUTPUT1, OUTPUT2
mass and energy balances at the feedzone mass and energy balances in between feed- zones	FEED1, FEED2  ENERGY, MOMENTUM RESEN, RESEN2, RESMOM, RESMOM2	FEED1, FEED2  ENERGY, MOMENTUM RESEN, RESEN2, RESMOM, RESMOM2	FEED1, FEED2  ENERGY, MOMENTUM RESEN, RESEN2, RESMOM, RESMOM2
equation of state	COWAT, GENERAL, HP, SAT, SOLVE, SATURATE, SUPST, TENS, TOP, TSAT, VISS, VISW	CO2, COWAT, ENTHCO2, GENERAL HSOLN, MU, SAT, SATURATE, SOLUB, SOLVEPX, SOLVET, SUPST, TENS, TFIND, TOP, TSAT, VISCO2, VISS, VISW, VOLCO2	COWAT, DENSE, HBRINE, NACL, PSALT, SAT, SATURATE, SOLUB, SOLVE, SUPST, SURF, TOP, TSALT, TSATN, VISC, VISS, VISW
initialization and determina- tion of grid nodes	FEEDNODE, MKGRID, NEWNODE, NEWNODE2	FEEDNODE, MKGRID, NEWNODE, NEWNODE2	FEEDNODE, MKGRID, NEWNODE, NEWNODE2

**TABLE 6.1 (cont.)****DESCRIPTION OF THE SUBROUTINES**

FUNCTION	SUBROUTINES		
	HOLA	GWELL	GWNACL
determination of flow regimes and flow characteristics	ARMAND, CHOKED, FRIC1, MOODY, REGIME	ARMAND, CHOKED, FRIC1, MOODY, REGIME	ARMAND, CHOKED, FRIC1, MOODY, REGIME
iteration routines	IT1, IT2, IT3, IT4, ITERATE1, ITERATE2, ITERATE3, ITERATE4, ITHHEAD, VINNA1, VINNA2	IT1, IT2, IT3, IT4, ITERATE1, ITERATE2, ITERATE3, ITERATE4, ITHHEAD, VINNA1, VINNA2	IT1, IT2, IT3, IT4, ITERATE1, ITERATE2, ITERATE3, ITERATE4, ITHHEAD, VINNA1, VINNA2
sorting routine for plotting	PLOTTA	PLOTTA	PLOTTA

**(1) Option 1 (ANS=1)**

This option needs the measured or known discharge condition at the wellhead (e.g. pressure, mass fraction  $\text{CO}_2$ , temperature and enthalpy). In addition, the flow rates and enthalpies of the feedzones are specified. Take note that for this option the last feedzone (at bottomhole) may not be specified since the program automatically calculates the condition of the last feedzone. The simulator then solves for the flowing temperature and pressure profile from the wellhead to bottomhole. The results can then be matched with the measured flowing temperature and pressure surveys to determine the relative contribution and fluid composition from the different feedzones.

**(2) Option 2 (ANS=2)**

In this option, the user specifies the required flowing wellhead pressure and bottomhole pressure, and the productivity indices (defined in Chapter 3), thermodynamic properties and composition of the fluid at each feedzone. The simulator then calculates for the flowing temperature and pressure from bottomhole to the wellhead and calculates the expected wellhead output (e.g. wellhead enthalpy, flowrate, pressure, temperature and fluid composition). For this option, unlike the input for option 1, all the feedzones have to be specified. This program can be used to

predict outputs of newly drilled wells using the parameters obtained from neighboring wells.

These three simulators have two major iteration subroutines that solve for the temperature and pressure in the well. Option 1 uses the subroutine VINNA1 and option 2 uses the subroutine ITHEAD.

(1) VINNA1

This subroutine calculates for the pressure, temperature and saturation profiles of a flowing well given the wellhead conditions and flowrate and enthalpy of each feedzone. The calculations proceed from the wellhead down to the bottom of the well.

(2) ITHEAD

This subroutine calculates for the flowrate and temperature at the wellhead given the required wellhead pressure. The productivity index, reservoir pressure and enthalpy (or temperature) at each feedzone have to be specified. The program will then compute for the flow contributions from each feedzone using Equation 3.13.

After the input data are read by the program, the calculations proceed using the equations as discussed in Chapter 3 and using either Orkizewski or Armand correlation. During the iteration procedure, negative temperatures or pressures are sometimes calculated if the flow is changing phase. This makes the program return to the previous node and add a new node to the grid, halfway between the previous node and the node where the unsuccessful iteration occurred.

The program execution may also be prematurely halted before the calculation reaches the bottom (or top) of the well. This happens for several reasons:

- (1) The program computes an impossible thermodynamic condition (e.g. negative temperature, pressure or mass fraction  $\text{CO}_2$  or NaCl).
- (2) Fluid is above critical condition.
- (3) Error in iteration.
- (4) Unsuccessful iteration.
- (5) The simulator calculates velocities in the well more than twice the choke velocity.
- (6) The specified number of grid nodes is more than 400.

In all these cases, error messages will be printed on the screen and on the file called HOLA.LOG, GWELL.LOG or GWNACL.LOG depending on which simulator was used. If Option 2 is used additional messages are printed both on the screen and in the file called \*.ITER (\* indicates the name of the simulator used). This file contains data regarding the iteration process.

After a successful run, the program goes back to the first menu. The user can then save the results into a file. Take note that the subroutine PLOTTA (used for sorting the output for plotting) prompts for a file name, thus the user should first save the results into a file (Option 6) before sorting can be done (Option 7).

The subroutine PLOTTA creates five files. These are :

- 1 pvsz.dat - this file has two columns. The first column contains the calculated pressure in MPa-gauge and the second column contains the corresponding depth in the well in meters.
- 2 tvsz.dat - this file contains temperature in °C (first column) and the corresponding depth in meters (second column).
- 3 geom.dat - contains the casing design. The first column is the well radius in centimeters and the second column is corresponding depth in meters.
- 4 fzon.dat - contains the location of the feedzones in the well. The first column is the location of the x-axis where the point is to be plotted (set = 0). The second column is the depth in the well, in meters, where the feedzone is located.
- 5 flpt.dat - contains the location where phase change occurs in the well. The first column is the location of the x-axis where the point is to be plotted (set = 0). The second column is the depth at which a phase change occurs.

Take note that the subroutine PLOTTA is only a sorting program and can be changed or modified to tailor the output of the subroutine to a specific plotting software that the user might be using.



## 6.2 INPUT DATA

The input data can either be read from a file or can directly be inputted through the keyboard. In case changes in the data are needed, the user can either use the system editor to edit the file, or he can read the file and input the necessary corrections directly from the keyboard. The program also provides an option to save the edited input deck when inputting or changes were done interactively.

The structure of the input files for Options 1 and 2 are described below. The variables can be specified in either F or E format as long as the variables in a line are separated by at least a space. Samples of the input deck, output and message files (\*.LOG and \*.ITER) are attached in Appendix A. Positive flows at the wellhead or feedzones indicate production and negative flows indicate injection. In the well, a positive velocity or flowrate means upward flow and negative means downward flow.

For Option 1, the wellhead condition can be specified by pressure, total mass fraction CO<sub>2</sub> or NaCl and either temperature or enthalpy. For both Options 1 and 2, the feedzone fluid property can be specified by either fluid enthalpy or temperature. The format of the input deck, description of the variables and their corresponding units are tabulated below.

## 6.3 OUTPUT

Samples of the output files are given in the Appendices. The output of the codes contains the fluid condition and composition at the wellhead. Aside from this, the location of the feedzones, the flow rate, enthalpy and fluid composition are tabulated. For Option 2, additional information at the feedzone are tabulated. These are the reservoir pressure, fluid saturation and the productivity indices. The output also tabulates the calculated thermodynamic properties, flow condition and fluid composition at each feednode. These are:

Depth	-	depth in the well
Press	-	pressure in Pa
Temp	-	temperature in °C
Dryness	-	steam mass fraction
Hw	-	liquid enthalpy

Hs	-	steam enthalpy
Vw	-	liquid velocity
Vs	-	steam velocity
Dw	-	liquid density
Ds	-	steam density
H_t	-	total enthalpy of the fluid
Rad	-	well radius
Reg	-	flow regime
		Sl - slug, Bu - bubble, Tr - transition, Mi - mist, 1p - single phase
XCO2	-	mass fraction CO <sub>2</sub> in total discharge
XNACL	-	mass fraction NaCl in total discharge

#### 6.4 ADDITIONAL NOTES ON RUNNING THE PROGRAM

Please note that the program always interpret the last feedzone to occur at the bottom of the well. In cases where the last feedzone does not occur at the bottom of the well, specify the well geometry with an apparent well depth equal to the depth of the last feedzone.

In setting up the well grid, make sure that the length of pipe section is a multiple of the grid node size (variable DELZ). Also specify the depth of the feedzone to be located exactly at the depth of a grid node.

In cases where the user doesn't want to include wellbore conductive heat losses, set THCON = 0. During program execution, if the message "Thermal resistance not defined" appears, this means that the criterion specified to get the approximate solution for wellbore heat losses is not satisfied (see Equations 2.5 and 2.6). In this case the program proceeds calculation without considering conductive heat losses.

If temperature is specified for the condition of the fluid at the wellhead or at the feedzone, GWNACL and HOLA will compare the given temperature with the saturation temperature. If the given temperature is equal to the saturation temperature, these two codes will interpret the fluid as saturated single-phase liquid. Also, when fluid is injected into the feedzone, the program will set the thermodynamic condition of the fluid entering the feedzone equal to the thermodynamic condition of the flowing fluid inside the wellbore.

At present the code can only handle a maximum of 400 grid nodes. If the user wants to increase the number of grid nodes, change the dimension statement of the variables WELL, WELL\_ST and STORE in the source codes.

**TABLE 6.2**  
**OPTION 1 INPUT DECK**

LINE	VARIABLE(S)
1	TEXT1
2	TEXT2
3	TEXT3
4	PTOP
5	HTOP
6	QTOP
7	XCTOP
8	LENGTH
9	THCON
10	RHOR
11	HCAP
12	TIME
13	NUSEC
14	SECL(i), RAD(i), EPS(i), DELZ(i), DEV(i)
:	: : : : :
13+NUSEC	SECL(NUSEC), RAD(NUSEC), EPS(NUSEC), DELZ(NUSEC), DEV(NUSEC)
14+NUSEC	NUPO
15+NUSEC	T_DEPTH(i), TEMP(i)
:	: :
14+NUSEC+NUPO	T_DEPTH(NUPO), TEMP(NUPO)
15+NUSEC+NUPO	NUFEED
16+NUSEC+NUPO	F_DEPTH(i), FLOW(i), ENTH(i), XC(i)
:	: : : :
15+NUSEC+NUPO+NUFEED	F_DEPTH(NUFEED-1), FLOW(NUFEED-1), ENTH(NUFEED-1), XC(NUFEED-1)

**NOTE:** For simulator HOLA, leave Line 7 blank and from Line 16+NUSEC+NUPO to Line 15+NUSEC+NUPO+NUFEED omit the variable XC

**TABLE 6.3**  
**OPTION 2 INPUT DECK**

LINE	VARIABLE(S)
1	TEXT1
2	TEXT2
3	TEXT3
4	PTOP
5	HTOP
6	QTOP
7	XCTOP
8	LENGTH
9	THCON
10	RHOR
11	HCAP
12	TIME
13	NUSEC
14	SECL(i), RAD(i), EPS(i), DELZ(i), DEV(i)
:	: : : : :
:	: : : : :
13+NUSEC	SECL(NUSEC), RAD(NUSEC), EPS(NUSEC), DELZ(NUSEC), DEV(NUSEC)
14+NUSEC	NUPO
15+NUSEC	T_DEPTH(i), TEMP(i)
:	: :
:	: :
14+NUSEC+NUPO	T_DEPTH(NUPO), TEMP(NUPO)
15+NUSEC+NUPO	NUFEED
16+NUSEC+NUPO	F_DEPTH(i), RESV91,i), RESV(3,i), RESV(4,i), RESV(6,i)
:	: : : :
:	: : : :
16+NUSEC+NUPO+NUFEED	F_DEPTH(NUFEED), RESV(1,NUFEED), RESV(3,NUFEED), RESV(4,NUFEED), RESV(6,NUFEED)

**NOTE:** For simulator HOLA, leave Line 7 blank and from Line 16+NUSEC+NUPO to Line 16+NUSEC+NUPO+NUFEED omit the variable RESV(6,i). Also, the simulators can compute for the expected fluid composition at the wellhead, the value 0 (or any value) can be entered in Line 7 for simulators GWELL and GWNACL.

The input variables and their units are tabulated below.

**TABLE 6.4**  
**DESCRIPTION OF THE INPUT VARIABLES**

VARIABLE	UNIT	REMARKS
DELZ(i)	m	Distance between two adjacent grid nodes for pipe section i
DEV(i)	degree (°)	Deviation angle measured from horizontal for pipe section i
ENTH(i)	°C or J/kg	Temperature or enthalpy of fluid at feedzone i
EPS(i)	m	Pipe roughness of section i
FLOW(i)	kg/s	Flow rate at feedzone i; + means producing (For Option 1 only)      - means injecting
F_DEPTH(i)	m	Depth of feedzone i
HCAP	J/kg-°C	Heat capacity
HTOP	°C or J/kg	Option 1: Wellhead fluid temperature or enthalpy Option 2: Bottomhole pressure
LENGTH	m	Well measured depth
NUFEED		Number of feedzones; max. = 10
NUPO		Number of reservoir temperature data points max. = 20
NUSEC		Number of pipe sections; max. = 50
PTOP	Pa abs	Wellhead pressure
QTOP	kg/s	Option 1: Wellhead flow rate
	Pa abs	Option 2: Max. error in wellhead pressure (difference between required and calculated wellhead pressures)
RAD(i)	m	Pipe radius
RESV(1,i)	Pa abs	Reservoir Pressure (For Option 2 only)
RESV(3,i)	°C or J/kg	Temperature or enthalpy of fluid at feedzone i (For Option 2 only)
RESV(4,i)	m <sup>3</sup>	Productivity index of feedzone i; see Eqn. 3.13 for definition (For Option 2 only)
RESV(6,i)		Mass fraction of CO <sub>2</sub> or NaCl of feedzone i
TEXT1		Character string; max. length = 80

VARIABLE	UNIT	REMARKS
TEXT2		Character string; max. length = 80
TEXT3		Character string; max. length = 80
THCON	W/m-°C	Thermal conductivity
TIME	s	Time since initial discharge
T_DEPTH(i)	m	Depth of temperature data point i
XC(i)		Mass fraction CO <sub>2</sub> or NaCl of fluid at feedzone i
XCTOP		Mass fraction in total discharge of CO <sub>2</sub> or NaCl at the wellhead Note that for Option 2, the fluid composition at the wellhead can be calculated. For Option 2, XCTOP may not be specified

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